STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: NEW ENGLAND GAS COMPANY'S :
GAS COST RECOVERY CHARGE : DOCKET NO. 3436

REPORT AND ORDER

I. NEGAS' SEPTEMBER 1, 2004 FILING

On September 1, 2004, New England Gas Company, ("NEGas"), a division of Southern Union, proposed increases in NEGas' Gas Cost Recovery ("GCR") factors for effect November 1, 2004. Specifically, NEGas proposed to increase its GCR factors on a per therm basis to: $0.8792 for residential and small commercial and industrial ("C&I") customers; $0.8717 for medium C&I customers; $0.8810 for large low load factor C&I customers; $0.8617 for large high load factor C&I customers; $0.9022 for extra large low load factor C&I customers; and $0.8385 extra large high load factor C&I customers. For a typical NEGas residential heating customer, this would result in a 3.2 percent increase or $43 per year, for a total bill of $1,378.[1] In addition, NEGas also filed to increase the Commodity Charge of its Natural Gas Vehicle Rate to $0.6652 per therm. Also, NEGas proposed various changes in gas marketer transportation factors.

In support of its filing, NEGas submitted the pre-filed testimonies of Peter Czekanski, Director of Pricing for NEGas, and Gary Beland, Director of Gas Supply for NEGas. In his pre-filed testimony, Mr. Czekanski explained the calculation of the GCR rates, the gas marketer transportation factors, and the Natural Gas Vehicle rate. Mr. Czekanski noted that NEGas' annual gas costs are projected to be $235 million. He

[1] The bill impact analysis incorporates NEGas' proposed increase in the Distribution Adjustment Clause ("DAC") factors effective November 1, 2004. The DAC factors increase is due to the reduction in the credit for earning sharing and weather normalization. Of the $43 increase, $14 was due to the GCR increase.

explained that the five gas cost components for the GCR factor are supply fixed costs, storage fixed costs, supply variable costs, storage variable product costs, and storage variable non-product costs.[2] He indicated that NEGas' current estimate of the deferred gas cost undercollection as of October 31, 2004 is $9.9 million. He also explained that the bill impact was due primarily to an increase in DAC factors rather the increases in the GCR factors. Furthermore, Mr. Czekanski noted that the Natural Gas Vehicle rate reflects the supply variable costs included in the GCR factor. He also updated the various gas marketer transportation factors, specifically, $0.0399 per therm for the FT-2 Firm Transportation Marketer Gas Charge and $0.0020 per percent of balancing elected per therm for Pool Balancing Charges.[3] Also, the weighted average upstream pipeline transportation cost was increased to $0.119 per therm of capacity.

In his pre-filed testimony, Mr. Beland discussed the estimated gas costs and the results of the Gas Purchasing Incentive Plan as well as the Asset Management Incentive Plan ("GPIP"). Mr. Beland stated that the GCR factors are based on prices for gas purchases locked under the GPIP and any non-locked purchases are based on the NYMEX strip as of the close of trading on August 12, 2004.[4]

Mr. Beland discussed the GPIP. He stated that the GPIP requires NEGas to start locking in future gas prices eighteen months prior to the delivery month, but ending two months before the month begins. NEGas must purchase 50% of projected purchases through this dollar cost-averaging approach, an increase from the 40% requirement prior to the amendments made to NEGas' purchasing plan in 2003. This mandatory purchase forms the benchmark for the incentive calculation. If the discretionary purchases are

[2] NEGas, Ex. 1 (Czekanski's direct testimony), pp. 1-3.
[3] Id., pp. 9-14.
[4] NEGas Ex. 2 (Beland's direct testimony), pp. 1-2.

made below the benchmarks, NEGas receives an incentive and if the discretionary purchases are made above the benchmark then NEGas receives a penalty. Mr. Beland also explained the asset management incentive. He stated that the incentive is based on the positive difference between the net fixed costs approved in NEGas' September GCR filing and the actual net fixed costs. Mr. Beland calculated that there was $978,227 in savings for purchased discretionary gas supply, and therefore, NEGas received an incentive of $160,816. He also calculated the estimated savings in fixed costs of approximately $1.8 million which results in an asset management incentive of $180,000. Lastly, Mr. Beland noted that NEGas added two resource contracts to serve the Westerly area with Yankee Gas Company and the Algonquin Gas Transmission Company.[5]

II. DIVISION'S DIRECT TESTIMONY

On October 12, 2004, the Division of Public Utilities and Carriers ("Division") submitted the pre-filed testimony of Bruce Oliver, a consultant. Mr. Oliver stated that Mr. Czekanski's calculation for the GCR factors appeared accurate. Mr. Oliver noted that in NEGas' September 2003 GCR filing, NEGas substantially understated its actual capacity release revenue and therefore, increased NEGas' net fixed costs for determining the asset management incentive. However, Mr. Oliver explained that this estimate was based on the uncertainty related to the agreement with ConocoPhilips regarding the level of assessment management revenue NEGas would receive. Furthermore, Mr. Oliver concluded that based on the timing of events relating to the completion of the ConocoPhilips agreement and the submission of NEGas' GCR filing, he found no reason to conclude NEGas withheld information regarding expected asset management revenue or purposefully understated its expected revenue at that time. In addition, Mr. Oliver

[5] Id., pp. 3-13.

noted that now that a higher level of overall capacity release revenue has been achieved, NEGas must assume the burden of justifying any significant reduction from that level as a basis for setting GCR charges and measuring incentive compensation for subsequent periods. Also, Mr. Oliver recommended that because of NEGas' increased use of LNG, the Commission may need to revisit the manner in which the allocation of LNG costs is determined between gas supply recovered through the GCR and maintenance of system pressures recovered through the DAC. Accordingly, Mr. Oliver recommended that NEGas be required to track its LNG use over the next winter and provide an assessment of the impacts of changes in its LNG dispatch on the appropriate allocation of LNG costs between the GCR and DAC prior to the time of its next annual GCR and DAC filings.[6]

In regards to the GPIP, Mr. Oliver concluded that the plan was producing the desired results. He stated that NEGas' new asset management arrangement with ConocoPhilips will help establish a more rigorous benchmark for measuring subsequent asset management benefits and incentives. Also, Mr. Oliver noted that NEGas has documented discretionary purchases that have produced noticeable gas cost savings for customers. Furthermore, Mr. Oliver emphasized that the comparatively small increase in GCR factors that NEGas is proposing, despite large increases in NYMEX natural gas prices, suggested a degree of success in the Commission's efforts to limit gas cost increases and control gas price volatility.[7]

Mr. Oliver expressed various concerns with certain elements of NEGas' gas purchasing. He maintained that NEGas should not make comparatively large storage injections for May and June because over the past two years natural gas prices have

[6] Div. Ex. 1 (Oliver's direct testimony), pp. 6-13.
[7] Id., pp. 14-15.

peaked during those months in anticipation for the summer. For instance, Mr. Oliver noted that approximately 42.5% of NEGas' projected annual storage injection requirements are planned for in May and June 2005.[8]

Also, Mr. Oliver indicated that in the last two winters NEGas relied on daily priced gas supplies for roughly 34% of its total forecasted winter sales service requirements. Mr. Oliver stated that daily priced purchases of natural gas exhibit high levels of price volatility. He noted that in January 2004, which he acknowledged was clearly an extreme example, NEGas purchased gas at prices in excess of $40 per MMBtu. He cited an average cost of $16.75 per Dth for 309,573 Dths of the most expensive daily priced purchases in January 2004. Mr. Oliver pointed out that NEGas can readily substitute daily purchases made during the month of supply for discretionary purchases made in advance of a gas supply month and therefore avoid the application of any incentive or penalty on the gas purchase. For instance, Mr. Oliver noted that NEGas' discretionary gas purchases averaged only about 15% of forecasted sales service requirements for the November 2003 through March 2004 period.[9]

Accordingly, Mr. Oliver recommended two changes in the GPIP. He argued that the incentives should be computed to conform with NEGas' fiscal years, which ends June 30th instead of November through October. This change would facilitate the Division's review of the incentives and penalties. Mr. Oliver also recommended closing the loophole that allows NEGas to use daily purchases to avoid making discretionary purchases. Thus, Mr. Oliver suggested that daily price purchases that NEGas can make within a gas supply month be limited to NEGas' actual sales of gas in excess of 95% of

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[8] Id., pp. 15-17.
[9] Id., pp. 17-19.

forecasted normal winter sales less actual LNG and propane send out for the supply month. As a result, any daily purchases made within a supply month in excess of the limit would be considered discretionary purchases and subject to incentives and penalties. Also, Mr. Oliver noted that while NEGas' projected fixed gas supply and fixed storage costs appear reasonable, NEGas should be required to explicitly address the reasonableness of its projected fixed gas supply and storage costs in its annual GCR filings. Lastly, Mr. Oliver stated that since August 12, 2004, NYMEX gas prices have risen sharply and NEGas' supply variable costs could increase by more than $23 million. As a result, he recommended that the Commission closely monitor the projected end-of-period deferred gas cost balance.[10]

III. HEARING

Following a duly published notice, the Commission conducted public hearings on October 14 and 18, 2004 at its offices at 89 Jefferson Boulevard, Warwick, Rhode Island. The following appearances were entered:

FOR NEGAS:	Cheryl Kimball, Esq. Robert Keegan, Esq.
FOR DIVISION:	Paul Roberti, Esq. Assistant Attorney General
FOR COMMISSION:	Steven Frias, Esq. Executive Counsel

The hearing on October 14, 2004, was solely to take public comment. On October 18, 2004, NEGas presented Mr. Czekanski and Mr. Beland as their witnesses. At the outset, Mr. Czekanski corrected his testimony to indicate that NEGas was seeking a 3.1 percent increase, or $42, of which $14 is a result of the GCR and $28 is a result of

[10] Id., pp. 19-24.

the DAC.[11] Mr. Beland disagreed with Mr. Oliver's proposed alteration to the GPIP regarding penalties and rewards for daily purchases. He stated that NEGas can not lock in 95 percent of its gas supply for any month, specifically November and April, because of weather fluctuations. However, he stated NEGas could lock in 65 percent of its gas supply. Also, Mr. Beland noted that approximately one-third of daily purchases for the winter were made in January 2004 due to weather at a point when gas was expensive, but there were daily purchases made in December 2003 which were reasonably priced and done to husband the storage. He concluded that NEGas' use of daily purchases has not been to evade the penalty but is part of its normal strategy. Also, Mr. Beland acknowledged that NEGas could be required to lock in a higher percentage of gas purchases and be less reliant on daily purchases. Mr. Beland agreed to Mr. Oliver's recommendations that the incentive be calculated on a fiscal year basis and that more levelized storage injections be made throughout the year.[12] Lastly, Mr. Beland indicated that the recent spike in NYMEX would "fade" if the winter is "normal or warmer than normal" based on levels of storage, injections, and imports of LNG. He stated: "I'm reasonably optimistic about the forward pricing."[13]

Under further cross-examination, Mr. Beland stated that based on recent NYMEX pricing the projected gas cost undercollection could be $14 million. He also estimated the asset management incentive to be approximately $181,000. Mr. Czekanski stated it would be impractical to report the status of the undercollection on a bi-weekly basis. Mr. Beland acknowledged that NEGas had made little discretionary purchases for January and February 2005, but stated the "biggest reason we chose not to buy" was because "we

[11] Tr. 10/18/04, p. 8.
[12] Id., pp. 53-54, 57-61, 64-68.
[13] Id., pp. 68-71.

felt that pricing was likely to get better". However, Mr. Beland agreed that due to natural gas being a rising market, the mandatory benchmark is a bit lower than the current market and that is one reason NEGas has not locked in additional supply for the winter.[14]

Under more questioning, Mr. Beland stated that NEGas' locked in gas purchases are made at a daily uniform quantity for the month and the most expensive daily gas purchase is needed only for a few days during peaking. If NEGas has excess gas supply, Mr. Beland stated that NEGas could store it or try to sell it and end up with a pipeline penalty. To avoid daily purchases during peak periods, Mr. Beland argued that NEGas would need additional storage which increases fixed costs. Also, in regards to discretionary purchases, Mr. Beland reiterated that if he believed that future winter prices were not going down, "I would have purchased the gas." Mr. Czekanski stated that for NEGas to reach its 70 percent requirement for the winter, NEGas must make discretionary purchases. Furthermore, Mr. Beland stated that "we do our best to optimize the purchasing to the benefit of the ratepayers. We don't do anything else" even "if it means we absorb some penalties."[15]

The Division presented Mr. Oliver as its witness. Mr. Oliver stated that one should avoid purchasing natural gas six to eight months prior to the month of supply. He also stated NEGas should look for alternatives to reliance on daily purchases such as storage. He agreed that within thirty days, NEGas and the Division could file recommended changes in the GPIP to minimize the need for daily purchases. Lastly, he recommended the Commission adopt NEGas' proposed GCR factors.[16]

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[14] Id., pp. 72-73, 77-79, 84-85, 90-91.
[15] Id., pp. 104, 108-111, 120-121.
[16] Id., pp. 162-166, 173, 179.

At an open meeting on October 21, 2004, the Commission approved NEGas' proposed GCR factors for effect November 1, 2004 and required NEGas to compute the incentives in the GPIP on a fiscal year basis.[17]

IV. AMENDMENTS TO THE GPIP

On November 19, 2004, NEGas, with the Division's consent, filed amendments to the GPIP. First, mandatory gas purchases would begin 24 months prior to the month of delivery and end 4 months prior to the start of deliveries. Second, by November 1st, NEGas would be required to make 80% of gas supply needed for each month of a normal December, January and February, and 75% gas supply needed for a normal November and March at fixed and capped prices. Third, the GPIP eliminated the provisions related to recommended purchase guidelines ("RPGs"). Fourth, the asset management incentive will be calculated on a July 1st to June 30th basis. Fifth, NEGas committed to attempt to reduce its reliance on daily priced purchases through increased storage and delivery transportation.[18]

V. TECHNICAL CONFERENCE

On December 9, 2004, the Commission held a technical conference at which NEGas and the Division were present to discuss the amendments to the GPIP. Mr. Beland was the witness for NEGas and Mr. Oliver was the witness for the Division. Mr. Beland indicated that gas prices were lower in the second year prior to delivery than in the year prior to delivery. He also stated there is a great deal of speculative activity in the

[17] The Commission adopted the Division's recommendation that NEGas be required to track its LNG use over the next winter and provide an assessment of the impacts of changes in its LNG dispatch on the appropriate allocation of LNG costs between the GCR and DAC prior to the time of its next annual GCR and DAC filings. Also, the Commission also adopted the Division recommendation that NEGas should be required to explicitly address the reasonableness of its projected fixed gas supply and storage costs in its annual GCR filings.

[18] Joint Ex. 1 (amended GPIP dated 11/19/04).

last few months before delivery. Mr. Beland was aware of some gas utilities that are close to NEGas' current levels of locked in gas prices for a winter but most do their purchasing right before the winter. Mr. Beland noted that NEGas procurement policy has saved ratepayers approximately $26 million since April 2001. Mr. Oliver stated that the incentive in the GPIP has worked generally to the benefit of ratepayers.[19]

Under cross-examination, Mr. Beland agreed that the prior GPIP envisioned a more typical market. Mr. Oliver indicated that gas is a long-term rising market. Mr. Beland and Mr. Oliver both concurred that in a rising market it is better to buy more gas earlier rather than later. Also, Mr. Beland and Mr. Oliver both agreed that locking in 75% to 80% of gas supply for winter months helps protect ratepayers from a price spike. Mr. Oliver argued that the proposed GPIP gives sufficient flexibility and discretion for NEGas in many areas. Mr. Beland indicated that comparing gas purchases made in advance of the closing gas price for the last trading date for the NYMEX of that month is a legitimate metric. Mr. Beland emphatically indicated that the incentive works and is difficult to achieve in a rising market. Also, Mr. Beland stated that the penalty is problematic, but acknowledged that in a rising market there are opportunities early in the process to make gas purchases that would not result in a penalty. In addition, Mr. Beland acknowledged that NEGas could request a waiver of a penalty under the GPIP.[20]

Mr. Beland maintained that NEGas' purchasing plan produced better results than the hedging program proposed by Paul Corby. He stated that at one point a Southern

[19] Tr. 12/9/05, pp. 5-7, 20, 36, 42.
[20] Id., pp. 42-45, 51, 60-63, 69.

Union unit utilized Mr. Corby's program and in comparison, NEGas consistently outperformed Mr. Corby's approach.[21]

At the conclusion of the technical conference, the Commission adopted the amended GPIP and directed the parties to develop changes to the incentive/penalty mechanism or metrics to gauge NEGas' performance.

VI. FURTHER AMENDMENTS TO THE GPIP

On March 10, 2005, in response to the hearing request, NEGas filed its recommendation for further amendments to the GPIP. NEGas discussed various options. First, NEGas discussed the use of a second benchmark based on the closing NYMEX price 18 months prior to the month of usage for determining incentives and penalties, as proposed in the original GPIP, but NEGas acknowledged that this benchmark would become stale and ineffective if prices moved higher. Second, NEGas mentioned that penalties could be waived for purchases that were higher than the benchmark, but below the cost of gas in the current GCR rates but, NEGas noted that this approach could also become stale and ineffective if prices moved higher. Third, NEGas referenced a dead band approach whereby gas purchases made within a certain range would be exempt from penalties, but NEGas indicated there would be difficulty in establishing the width of the dead band. Fourth, NEGas outlined a circuit breaker approach whereby NEGas would make gas purchases exempt from any penalties with the approval of the Division and the Commission, but NEGas explained that delays in the process could result in missed opportunities and furthermore, uncertainty in the market makes it difficult to determine how much and when to purchase the gas. Fifth, NEGas referred to a time limit approach whereby if the benchmark was consistently below the market for six months

[21] Id., pp. 74-77.

then NEGas could make discretionary purchases not subject to penalties, but NEGas admitted that this approach would have arbitrary time limits which could create an incentive for the company to make purchases based on the arbitrary time limit. Sixth, NEGas mentioned the elimination of penalties but understood that it would create an asymmetrical incentive system.

In the end, NEGas recommended increasing the level of mandatory purchases under the GPIP from 50 percent to 70 percent for the months of November through March. This modification would allow NEGas to make these purchases without incurring a penalty and would avoid short-term market volatility. Also, NEGas discussed metrics to measure NEGas' performances of gas purchasing. NEGas noted that the mandatory benchmark is a metric and stated that the comparison of discretionary purchases to the monthly closing price of NYMEX is also a metric. NEGas went on to discuss the difficulties of creating additional metrics.[22]

On March 29, 2005, the Division filed a memo from Bruce Oliver in response to NEGas' filing. Mr. Oliver recommended that the mandatory level of gas purchases be increased to 70 percent for all months. Mr. Oliver discussed the difficulties of creating metrics but opined that metrics could be developed comparing the relative magnitude of fluctuations or changes in NEGas' average gas commodity purchases or costs to the NYMEX over long-term periods such as a year or more.[23]

[22] NEGas' 3/10/05 filing.
[23] Division's 3/29/05 filing.

On April 6, 2005, NEGas filed a response to the Division's memo. NEGas agreed to increase the mandatory level of gas purchases to 70 percent for all months except April and October which would be increased to 60 percent because of weather fluctuations.[24]

At an open meeting on April 7, 2005, the Commission approved NEGas' proposed modification to the GPIP to increase the level of mandatory purchases to 60 percent for April and October and 70 percent for the remaining months.[25] In addition, the Commission agreed that the circuit breaker approach discussed by NEGas should be developed and that metrics to evaluate NEGas' performance should be explored.

VII. NEGAS' APRIL 1, 2005 FILING

On April 1, 2005, NEGas proposed increases in NEGas' GCR factors for effect May 1, 2005. Specifically, NEGas proposed to increase its GCR factors on a per therm basis to: $0.9530 for residential and small C&I customers; $0.9428 for medium C&I customers; $0.9520 for large low load factor C&I Customers; $0.9328 for large high load factor C&I customers; $0.9733 for extra large low load factor C&I customers; and $0.9096 for extra large high load factor C&I customers. For a typical NEGas residential heating customer, this would result in a 4.9 percent increase, or $17, from May through October 2005. In addition, NEGas also filed to increase the Commodity Charge of its Natural Gas Vehicle Rate to $0.737 per therm.

In support of its filing, NEGas submitted the pre-filed testimonies of Peter Czekanski and Gary Beland. In his pre-filed testimony, Mr. Czekanski stated that the GCR rates are being increased to reflect the costs being incurred by NEGas for the summer because NYMEX gas prices have increased significantly since September 2004.

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[24] NEGas' 4/6/05 filing.

[25] The amended GPIP filed on April 15, 2005 is attached as Appendix A hereto and is incorporated by reference herein.

Mr. Czekanski explained that NEGas is only changing the supply variable component. Without a change in the GCR rates, the projected gas cost undercollection at October 31, 2005 would be $11.7 million, but by implementing the proposed GCR factor, Mr. Czekanski calculated the projected end-of-period deferred gas cost balance would be $7.3 million.[26] In his pre-filed testimony, Mr. Beland stated that actual gas prices for November 2004 through April 2005 are $0.46 per dekatherm higher on average than the NYMEX prices projected in the original filing in September 2004. Also, he stated that future prices for May through October 2005 are on average $1.28 higher than the original filing. He stated that this GCR filing is based on NYMEX prices as of March 28, 2005. He also noted that NEGas' fixed costs have been updated to incorporate a rate reduction associated with Algonquin contracts that take effect in April.[27]

VIII. DIVISION'S MEMORANDUM

On April 26, 2005, the Division filed a memorandum by Bruce Oliver. Mr. Oliver indicated that since its initial GCR filing in September 2004 the NYMEX gas price strip has increased 21 percent. Also, he noted that despite comparatively high storage inventories for the time of year, summer gas prices have not decreased because of speculative trading. Mr. Oliver stated that a GCR rate increase would reduce the size of the projected deferred gas cost balance. He also noted that the current NYMEX gas strip for next GCR period is 25.8 percent above the comparable NYMEX strip in NEGas' GCR filing of September 2004. In conclusion, Mr. Oliver determined that an increase in the GCR rates in May 2005 would mitigate an increase in the GCR in the fall of 2005.[28]

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[26] NEGas Ex. 5 (Czekanski's direct testimony), pp. 1-5.
[27] NEGas Ex. 6 (Beland's direct testimony), pp. 1-7.
[28] Div. Ex. 2 (Oliver's memorandum).

IX. HEARING

After duly published notice, the Commission conducted a public hearing on April 29, 2005 at its offices on 89 Jefferson Boulevard in Warwick, Rhode Island. The following appearances were entered:

FOR NEGAS:	Cheryl Kimball, Esq.
FOR DIVISION:	Paul Roberti, Esq. Assistant Attorney General
FOR COMMISSION:	Steven Frias, Esq. Executive Counsel

At the hearing, the Commission heard public comment in favor of changing the Commission's Termination Rules. NEGas presented Mr. Czekanski and Mr. Beland as witnesses while the Division presented Mr. Oliver. Mr. Oliver stated that current gas prices are 21 percent higher than the rates set in the fall. He also indicated that NEGas' proposed GCR rates are lower than the rate currently in place for his local gas utility in Virginia. Mr. Beland and Mr. Oliver agreed that they were not familiar with any other gas utility which purchases gas as far ahead or as much for the winter as does NEGas. Mr. Oliver agreed that gas is a long-term rising market and that in such a market, a good strategy to avoid price spikes is to buy gas earlier and as much as you can. Also, Mr. Oliver testified that NEGas' purchasing plan has been effective in mitigating price increases and price spikes for residential ratepayers and is one of the best programs in the nation.[29]

Under further cross-examination, Mr. Oliver acknowledged that NEGas' purchasing plan is a prudent, long-term, cost average method of purchasing as opposed to financial hedging. Mr. Oliver agreed that it is possible to measure the performance of the

[29] Tr. 4/20/05, pp. 53, 58-62, 65-66.

gas purchasing program against market based benchmarks. He also discussed the trade-offs between commodity costs and capacity costs.[30] In addition, Mr. Oliver stated that a monthly gas adjustment factor is not in the best interests of consumers while the price stability provided through the existing process is a clear benefit for consumers. Also, Mr. Oliver admitted that NEGas' gas procurement plan is a risk management plan.[31] At the conclusion, the Commission approved, for effect May 1, 2005, the GCR factors and NGV rate filed by NEGas on April 1, 2005.

COMMISSION FINDINGS

I. GCR INCREASES

Once again, the Commission is confronted with the issue of whether to increase NEGas' GCR rates in order to reduce the projected gas costs undercollection and to better reflect current gas costs. Regrettably, since April 1, 2003, NEGas ratepayers have been forced to pay essentially semi-annual rate increases of approximately five percent. On November 1, 2004, NEGas ratepayers received a 3.1 percent increase and on May 1, 2005 ratepayers experienced a 4.9 percent increase. These periodic increases are the result of a long-term rising market for wholesale natural gas.

Also, these increases are necessary to minimize and eventually eliminate the gas cost undercollection. With the increase for May 1, 2005, the undercollection is now at approximately $2.1 million.[32] Clearly, the Commission is making progress towards its goal of not having a large undercollection in energy costs.

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[30] Id., pp. 66-68, 75, 82-83.
[31] Id., pp. 97-98, 100.
[32] NEGas 5/20/05, gas undercollection status report.

II. GPIP AMENDMENTS

In addition to the goal of minimizing undercollections in energy costs, the Commission has a well established policy of promoting rate stability.[33] Unfortunately, in a rising market, it is difficult if not impossible to ensure a stable fixed rate. Instead, the Commission has approved, essentially, semi-annual rate increases of approximately five percent. In an attempt to further promote the ratemaking objective of price stability, the Commission has adopted various changes to the GPIP.

The GPIP adopted in 2003 was designed for a more typical market where wholesale gas prices rose and fell within certain parameters. Instead, the wholesale gas market has clearly shown a long-term rising trend. Accordingly, the GPIP needed to be amended to reflect this change in market conditions.

In a rising market, a good purchasing strategy, put in simplistic terms, is to buy as much as you can as soon as you can. The amendments to the GPIP generally reflect this approach. The first major amendment was to mandatory purchases so that they are made beginning 24 months prior to the month of delivery and ending 4 months prior to the month of delivery. This replaces the current approach of beginning mandatory purchases 18 months before the month of delivery and ending 2 months prior to the month of delivery. As a result, in a rising market, this will cause NEGas to make more purchases that are lower priced and at the same time reduce NEGas' exposure to gas prices reflective of speculative pressures in the immediate months prior to delivery.

A second major amendment was to require NEGas to purchase by November 1st, 80 percent of gas supply needed for each month of a normal December, January and February as well as 75 percent for the months of November and March at fixed capped

[33] See e.g. Order Nos. 17970, 17606 and 17444.

prices. This provision replaces the current provision that requires NEGas to purchase 70 percent of gas supply needed overall for a normal winter by October 20th of each year. Accordingly, this amendment reduces NEGas' need to make gas purchases during the winter when gas prices are high and the most volatile, in particular, daily gas purchases. Furthermore, NEGas committed to try to reduce its reliance on daily priced gas purchases through increased storage and delivery transportation. Daily gas purchases are particularly high when it is colder than normal. Of course, NEGas should determine whether any increase in fixed costs is a net benefit to ratepayers.

A third major amendment was to increase the level of mandatory gas purchases of the GPIP from 50 percent for each month to 60 percent for April and October, and 70 percent for the remaining months. This is necessary because in a rising market, a dollar cost averaging approach generally produces superior cost savings than trying to time the market through opportunities available with discretionary gas purchases. Also, in a rising market, the incentive/penalty mechanism may create a disincentive for NEGas to make discretionary purchases because the price of the discretionary gas purchase could be higher than the mandatory purchase benchmark. The increase in the mandatory purchase level per month significantly minimizes the exposure NEGas would have to penalties in a rising market. Furthermore, NEGas should be aware that it is encouraged to ask for a waiver of any penalty in order to make gas purchases if it believes it is in the best interest of ratepayers based on current market conditions. This was referred to by NEGas as the "circuit breaker" approach.

The fourth major amendment was to eliminate the Recommended Purchase Guideline ("RPGs"). These RPGs have been based on stale gas prices. In a rising market, the RPG approach is inherently flawed because it is based on historical data which becomes increasing irrelevant and stale as time passes. However, in a rising market, it is logical to make gas purchases when the price momentarily dips below the gas prices embedded in the GCR rate. This purchasing approach would lead to a more stable GCR rate. Thus, NEGas is encouraged to and, if necessary, request flexibility from the Commission to make gas purchases that will help maintain the current GCR rate.

From time to time, the Commission should evaluate the effectiveness of its regulatory policies. Objective metrics or standards can be a vital component for an effective evaluation. In gas procurement, the two general approaches to determine effectiveness of a gas purchasing plan are to compare gas costs of the gas purchasing plan to market prices or to compare gas costs of the purchasing plan to the gas costs or gas purchasing plans of similar gas utilities.

In regards to a comparison to market prices, NEGas has presented a metric, which compares the actual NYMEX monthly closing gas price with the weighted average of the locked-in NYMEX gas price for the same month under NEGas purchasing plan. This is a valid metric because the monthly NYMEX closing gas price is utilized in other utility industries to measure fuel costs.[34] Since April 2001, when the Commission approved NEGas' dollar cost averaging approach, NEGas has realized savings of approximately $29,554,202 as of May 2005.[35] The savings become even more apparent if the gas purchases are calculated starting with November 2002, when the current long-term rising gas market began. Since November 2002, NEGas has savings of approximately

[34] The fuel trigger in some of Narragansett Electric's Standard Offer contracts are based, in part, on the last three days of the monthly NYMEX closing gas price.
[35] NEGas Record Response 1-1 dated 5/8/05.

$46,910,070 as of May 2005. Based on these statistics, it is apparent that NEGas' gas purchasing strategy has resulted in significant savings for ratepayers in this long-term rising market for gas.

As for comparing NEGas' gas costs or purchasing plan to the gas costs or purchasing plans of other gas utilities, this is a difficult endeavor due to difference in customer composition, availability of gas recourses such as pipeline and storage, and the transportation costs of delivering the gas. However, some pertinent analysis can be made by comparing NEGas' gas costs to the gas costs of other gas utilities.[36] In the New England region, gas utilities have relatively similar costs associated with the transportation of gas such as pipeline and fuel costs as well as access to similar gas resources such as pipeline and storage. In comparing the GCR rates charged by New England gas utilities to their residential heating customers for the winter of 2004-2005, which extends from November 1st to April 30th, it appears that NEGas had essentially the lowest gas costs for residential heating customers this past winter out of the eighteen New England gas utilities.

For this past winter, NEGas' GCR rate for residential heating customers was $0.879 per therm. In Maine, the one gas utility with more than 1,000 customers, Northern Utilities, had a GCR rate of $1.15 per therm. In New Hampshire, Keyspan had its GCR rate set at $0.953 per therm and Northern Utilities had its GCR rate set at $0.979 per therm. In Vermont, Vermont Gas had a GCR rate of $1.053 per therm. In Connecticut, the three gas utilities have part of their gas costs charged through base rates,

[36] In a rising market, a purchasing plan which requires a utility to purchase large amounts of gas significantly earlier than the month of usage should result in lower costs. In a typical market, however, such a purchasing plan would likely lead only to a more stable GCR rate, which is also a Commission policy objective. Since this is a rising market, the Commission can assess the effectiveness of NEGas' purchasing plan by measuring NEGas' gas costs with other comparable gas utilities.

and part charged through their Purchased Gas Adjustment ("PGA") rates. For Connecticut Natural Gas, its combined GCR rate for a residential heating customer ranged from $0.913 to $0.958 per therm. For Southern Connecticut Gas, its combined GCR rate for a residential heating customer ranged from $0.979 to $1.023 per therm. For Yankee Gas, its combined GCR rate for a residential heating customer ranged from $0.929 to $1.032 per therm.

In Massachusetts, there are 10 gas utilities of which three are comparable to NEGas in size. Boston Gas/Keyspan had GCR rates for residential heating customers in the range of $0.947 to $1.031 per therm. Bay State's GCR rate for residential heating customers was in the range of $1.005 to $1.245 per therm. NStar's GCR rate for residential heating customers ranged from $0.850 to $0.996. Since NStar's GCR rate was $0.996 for November through January, and $0.850 for February through April, it is clear that overall, for the winter, NEGas' GCR rate of $0.879 was lower than NStar's average rate for the winter. In regards to Massachusetts' smaller gas utilities, the GCR rates for residential heating were as follows: Berkshire's GCR rates ranged from $0.868 to $0.989 per therm; Blackstone's GCR rate was $0.909 per therm; Colonial Gas' GCR rates ranged from $0.901 to $1.029 per therm; Fall River's GCR rates ranged from $0.989 to $1.119 per therm; Fitchburg Gas' GCR rates ranged from $0.920 to $0.956 per therm; and North Attleboro Gas' GCR rates ranged from $1.016 to $1.056 per therm. Only Essex Gas had a lower GCR rate than NEGas, ranging from $0.760 to $0.899 per therm. However, this was only due to the fact that Boston Gas/Keyspan subsidized the gas costs for Essex, and this subsidization will soon end.[37] Thus, in reality, NEGas had the lowest gas costs for residential heating customers in New England for the past winter. NEGas'

[37] Mass. DTE Order in Docket No. 04-66, pp. 13, 16-17.

lower gas costs must be to some extent a reflection of the effectiveness of NEGas' purchasing plan in a rising market for gas.[38]

As shown above, these metrics, utilizing monthly closing NYMEX gas prices and GCR rates from other New England utilities, have shown that NEGas' purchasing approach has been successful in reducing gas costs for ratepayers. However, the Commission will attempt to develop other metrics or standards to determine if NEGas' purchasing plan is succeeding or could perform better. This Commission expects the full cooperation of NEGas in this endeavor. Of course, the Commission is cognizant that NEGas' GPIP may not epitomize perfection, but perfection eludes every mortal endeavor. Instead, the Commission can only continue to make its best efforts to build upon the success that has already been achieved. For instance, the Commission can examine if there are cost-effective approaches to reduce NEGas' reliance on daily gas purchases during cold snaps. Also, the Commission hopes that NEGas will explore a risk management plan which include appropriate financial hedges so as to minimize NEGas' need to make daily gas purchases during severe cold weather. For the moment, the Commission is, and the Division and NEGas should be, pleased and proud that NEGas' GPIP has resulted in such large savings to customers as compared to market prices, and that NEGas' gas costs for residential heating customers were the lowest in New England this past winter.

[38] These GCR rates are available to the public on the respective websites of these state regulatory commissions.

Accordingly, it is

(18273) <u>ORDERED</u>:

1. The Gas Cost Recovery factors filed by NEGas on September 1, 2004, set forth on a per therm basis, of: $0.8792 for residential and small commercial and industrial customers; $0.8717 for medium commercial and industrial customers; $0.8810 for large low load factor customers; $0.8617 for large high load factor customers; $0.9022 for extra large low load factor customers; and $0.8385 for extra large high load factor customers, are approved for effect November 1, 2004 through October 31, 2005.
2. The Gas Marketer Transportation factors filed by NEGas on September 1, 2004, of: $0.0399 per therm for FT-2 Firm Transportation Marketer Gas Charge; $0.0020 per percent of balancing elected per therm for Pool Balancing Charge; and a weighted average upstream pipeline transportation cost of $0.119 per therm of capacity are approved for effect November 1, 2004 through October 31, 2005.
3. The Natural Gas Vehicle Rate filed by NEGas on September 1, 2004 of $0.6652 per therm is approved for effect November 1, 2004.
4. The Gas Cost Recovery factors filed by NEGas on April 1, 2005, set forth on a per therm basis, of: $0.9503 for residential and small commercial and industrial customers; $0.9428 for medium commercial and industrial customers; $0.9520 for large low load factor commercial and industrial customers; $0.9328 for large high load factor customers; $0.9733 for extra large low load factor customers; and $0.9096 for extra large high load factor customers, are approved effective for consumption on and after May 1, 2005 through October 31, 2005.

5. The Natural Gas Vehicle Rate filed by NEGas on April 1, 2005 of $0.737 per therm is approved for effect May 1, 2005.
6. The modifications to the Gas Procurement and Asset Management Incentive Plan filed by NEGas on November 19, 2004 and April 6, 2005 are approved.
7. NEGas shall comply with the reporting requirements and all other findings and directives contained in this Report and Order.

EFFECTIVE IN WARWICK, RHODE ISLAND PURSUANT TO OPEN MEETING DECISIONS ON OCTOBER 21, 2004 AND APRIL 7, 2005 AND BENCH DECISIONS ON DECEMBER 9, 2004 AND APRIL 29, 2005. WRITTEN ORDER ISSUED JUNE 16, 2005.

PUBLIC UTILITIES COMMISSION

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Elia Germani, Chairman

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*Kate F. Racine, Commissioner

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Robert B. Holbrook, Commissioner

*Commissioner Racine concurs with the November 1, 2005 GCR increase but is unavailable for signature. Commissioner Racine did not participate in the remainder of the proceeding following her retirement.

Appendix A

Gas Procurement and Asset Management Incentive Plan for NEG

Revised Effective April 7, 2005

I. Objectives

A. To encourage the New England Gas Company ("NEG" or "Company") to achieve lower overall gas commodity costs for its customers; and

B. To encourage the Company to minimize fixed costs and obtain the maximum value from its pipeline, storage and supply resources.

II. Structure of the Incentive Plan

A. The Incentive Plan ("Plan") has two components

1. A Gas Procurement Incentive Program ("GPIP"); and

2. An Asset Management Incentive Program ("AMIP").

B. This Plan became effective June 1, 2003. It will be reviewed with each gas cost recovery ("GCR") filing. The Company will file Plan results semi-annually at the end of January and July. These reports shall include reporting all Plan activity and results through the end of the month prior to the filing.

1. Gas Procurement Incentives apply only to discretionary purchases made on or after June 1, 2003. The first month for which the incentive will be calculated under the Plan will be November 2003.

2. Beginning in 2005, the AMIP applies to fixed gas supply expenditures for the 12-months ended June 30th of each year except for the 2004/2005 year, which will include the period from November 1, 2004 to June 30, 2005.

C. Limits on Incentives – Both the GPIP and the AMIP, will be subject to limits on the magnitude of incentives applicable to the Company in each fiscal year.

1. For the Gas Procurement Incentive Program limitations are placed on the maximum amount of incentives that can be earned or

penalties paid by NEG for each fiscal year. For at least the first two years of the program (i.e., through June 30, 2005):

a. NEG may not earn more than $1,000,000 in Gas Procurement Incentives in any fiscal year; and

b. NEG may not be exposed to penalties of more than $500,000 in any fiscal year.

2. For the AMIP the maximum amount of incentive for the Company for a one-year period will be $400,000. Since the Rhode Island Public Utilities Commission ("Commission") annually reviews and can exercise control over the amount of fixed gas supply costs projected for the coming GCR period, no specific penalty structure is proposed to address unanticipated increases in Asset Management costs.

D. The Company will file its forecasted normal weather natural gas purchase requirements with its annual GCR filing. In addition, whenever the Company updates its annual forecast of projected purchases at the time of the annual update or in the event that an adjustment based on migration is warranted, it will file support for the revised purchase forecast with the Commission and Division.

III. <u>The Gas Procurement Incentive Program</u>

A. The Company will make purchases of natural gas incorporating the lock of the NYMEX Henry Hub portion of the variable cost. For any future gas supply month the Company will make three types of gas purchases:

1. Mandatory Purchases

a. Are defined as mandatory monthly purchases of gas volumes made in uniform monthly increments. (Mandatory purchases will vary as the forecast of purchases is updated periodically.)

b. Will equal 60% of forecasted normal weather gas purchase requirements for the April and October gas supply months and 70% of forecasted normal weather gas purchase requirements for the remaining ten months. Purchases will be based on the forecast of requirements in place when the purchases are made.

c. Will be purchased in uniform monthly increments on a mandatory basis starting 24 months prior to the month of delivery and ending 4 months prior to the start of deliveries.

d. The first purchases made each month will be deemed the Company's mandatory purchases up to the amount of the Company's uniform monthly purchase requirement unless such purchases are made under the recommended purchase guidelines ("RPG") as defined below.

2. Discretionary Purchases

a. Are defined as the physical volume purchased at least 6 business days prior to the start of the delivery month for delivery to the system or storage in excess of the Mandatory Purchase requirements in a month and which, in aggregate, do not exceed 45% of forecasted normal weather gas purchase requirements for a given gas supply month.

b. The cost and benefit of any financial hedges will be included in the calculation of the average unit price.

3. Other Discretionary Purchases Not Subject To Incentives

a. LNG and propane supplies.

b. Supplies that lock in price but are not part of the program i.e., the Distrigas FCS contract.

c. Purchases made less than 6 business days prior to the beginning of the month, during the month or under a contract which does not allow for the locking of the price.

d. Purchases made due to updated levels of forecasted migration of throughput volumes from transportation service to sales service.

B. Computation of Gas Procurement Incentives

Gas Procurement Incentives will be determined on the basis of comparisons of the volume-weighted average cost per dekatherm of Discretionary Purchases made after June 1, 2003, and the volume weighted average cost per dekatherm of mandatory gas purchases made after June 1, 2003 for the same gas supply month. All comparisons will be based on the NYMEX portion of the variable cost per dekatherm of the purchased gas supply.

C. Any purchases made for a future gas supply month, excluding other Discretionary Purchases not subject to incentives as shown in III.A.3, that are in excess of the mandatory purchase requirement for the month, will be deemed discretionary purchases.

D. The timing of discretionary purchases is left solely to the discretion of the Company. However, beginning in November 2005 the Company will make sufficient Discretionary Purchases by November 1st of each year, such that a minimum of 80% of supply needed for December, January and February and 75% of supply needed for a normal November and March will be at a fixed or capped price. The fixed and capped supplies will include all forward purchases, financially based hedges, DOMAC FCS contract purchases, LNG purchases and storage supplies.

F. After all purchases for forecasted gas requirements for a given gas supply month are completed, the volume-weighted average cost of Discretionary Purchases is computed.

1. If the weighted average cost of Discretionary Purchases is less than that for Mandatory Purchases, NEG earns a positive incentive equal to 10% of the difference between the weighted average cost of Discretionary Purchases and the weighted average cost of Mandatory Purchases in dollars per dekatherm multiplied by the actual volume of Discretionary Purchases.

2. If the weighted average cost of discretionary purchases is greater than that for mandatory purchases the Company will be assessed a penalty (i.e., negative incentive) equal to 10% of the difference in dollars per dekatherm between the weighted average cost of Discretionary Purchases and the weighted average cost of Mandatory Purchases for the same gas supply month multiplied by the actual volume of Discretionary Purchases.

3. If the weighted average cost of Discretionary Purchases is more than $0.50 below the weighted average cost of Mandatory purchases then NEG will receive a Meritorious Performance Bonus equal to 10% of the difference between the weighted average cost of Discretionary Purchases and the weighted average cost of Mandatory Purchases multiplied by the actual volumes of Discretionary Purchases.

IV. The Asset Management Incentive

A. For each gas supply year during the effective period of this incentive program, NEG will earn a dollar incentive based on reductions achieved in fixed gas supply and fixed storage costs from the amounts projected as accepted by the Commission for each gas supply year. The net effect of fixed costs recovered from marketers under the capacity assignment feature of the Company's transportation program will not be counted in the calculation of the incentive. The calculation will include all fixed costs associated with gas supply, asset management fees or credits, capacity release credits and off-system sales margins.

B. To discourage achievement of fixed costs savings through the manipulation of gas commodity purchases, the amount of the Asset Management Incentive shall be dependent upon the Company's success in its Gas Procurement activities.

1. If the Company's actual gas procurement costs at the time of the Company's last annual GCR filing are **below** its projected gas procurement costs on a dollars per dekatherm basis, then NEG shall be provided an Asset Management incentive equal to 20% of the amount by which the sum of the Company's actual fixed gas supply costs and fixed storage costs are below the projected fixed gas supply and fixed storage costs accepted by the Commission for the gas supply year.

2. If the Company's actual gas procurement costs at the time of the Company's last annual GCR filing are **above** its projected gas procurement costs on a dollars per dekatherm basis, then NEG shall be provided an Asset Management incentive equal 10% of the amount by which the sum of the Company's actual fixed gas supply costs and fixed storage costs are below the projected fixed gas supply and fixed storage costs accepted by the Commission for the gas supply year.